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METHANE

A ticking time bomb for Australian investors

The emissions risks facing Australia's oil & gas and coal mining sectors

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Key Findings

Investors have an opportunity to incentivise more rapid action on methane – a potent greenhouse gas and a major contributor to fossil fuel companies' Scope 1 emissions – by incorporating methane reporting and abatement into their engagement with companies.

Leading companies in Australia's oil & gas and coal mining sectors are not taking sufficient action to reduce methane emissions, while planning substantial expansions of production that would outweigh any existing abatement action, relying instead on buying carbon credits to meet their climate-related targets.

By not implementing structural methane abatement measures, companies will rely on purchasing carbon offsets, increasing risk exposure in the event of a rising Australian carbon price.

Methane abatement can be undertaken with mature technologies at relatively low cost, and offers potential financial benefits for companies through the use and sale of captured gas.

Executive Summary

Greater methane abatement action is required by oil & gas and coal mining companies in Australia to decrease their climate-related risk exposure and reduce greenhouse gas emissions.

Methane is a potent greenhouse gas that increases the climate-related risks facing companies in these sectors. Methane's significant contribution to fossil fuel companies' Scope 1 emissions means without strong mitigation action companies risk missing their own emissions reduction targets or breaching regulatory emissions requirements. Methane abatement could also offer financial opportunities through the use or sale of captured methane.

There is a significant risk that companies' self-reported methane emissions are underestimated in Australia. Emissions could be two times higher than reported for oil & gas companies and three times higher for open-cut coal miners. This is largely due to current estimation methods relying only on production-based emissions factors, which may not incorporate comprehensive empirical data, and do not require third-party verification. Additionally, companies are not fully utilising 'top-down' methods such as satellite monitoring, remote sensing and flyovers to verify reported emissions and monitor for leaks or plume events. Meanwhile, companies are not taking strong action specifically aimed at cutting methane emissions and generally report carbon dioxide-equivalent rather than individual greenhouse gases.

This report examines the actions of five companies in these sectors: Woodside, Santos, APA Group, BHP and Whitehaven. All five have significant plans to extend or increase production. This will lead to increased methane emissions unless structural abatement activities or net decreases in production are undertaken concurrently. All five companies have taken no or limited abatement action to date. For those that have, the scale of methane abatement is outweighed by the scale of planned production growth and expansions.

However, abatement action is possible and, could even be financially beneficial for companies. Methane abatement technology is technologically mature, and could be undertaken at relatively low costs. IEEFA's analysis found that abatement in coal mining could be rolled out at an average cost of AU$1 per tonne of coal. For oil & gas companies, methane abatement could be done at an overall net financial benefit due to the options to use or sell the methane gas captured.

Investors have an opportunity to incentivise more rapid action on methane emissions by incorporating methane reporting and abatement into their engagement with fossil fuel companies. Doing so would promote accurate, transparent methane emissions disclosures, verifiable methane measurements and reductions, and stricter performance standards.

Companies' methane risk exposure summary

	Oil and Gas			Coal	
	APA	woodside	Santos	BHP	Whitehaven
Overall Methane Risk Exposure	Moderate	Moderate	Moderate	High	High
Reporting Risk	Low	Moderate	Moderate	High	High
Emissions Target Risk	Low	High	High	High	High
Expansion Plans Risk	High	High	High	High	High
Abatement Action Risk	Moderate	Moderate	Moderate	High	High
Methane Costs Risk	Low	Low	Moderate	Moderate	Moderate

Oil & gas overview
Woodside, Santos and APA Group

Given the risks and potential benefits, Australian oil & gas companies should prioritise improved methane measurement and abatement.

Methane emissions from gas production in Australia are significantly higher than from oil production, as gas production is more than 10 times that of crude oil. In the gas sector, methane is emitted through the entire supply chain, with about two thirds coming from production and one third from transmission, distribution and storage.

Woodside and Santos are involved in the most methane-intensive parts of the gas supply chain, meaning their methane reduction strategies will have a relatively large impact on the sector's emissions. However, APA owns the only available gas infrastructure in many of the regions where they operate, meaning efforts to reduce emissions are important for all three companies.

Woodside operates two liquefied natural gas (LNG) plants in Western Australia (WA) – the North West Shelf (NWS) and Pluto – and is a partner in the Gippsland Basin Joint Venture offshore gas production facility. Woodside expanded international operations in 2022 through a merger with BHP's petroleum operations, thereby diversifying its assets by geography and adding more oil production to its portfolio. It will more than double the size of its Pluto LNG plant next year when the Scarborough gas field starts production.

Santos operates two LNG plants in Australia: Darwin LNG and Gladstone LNG. It has a significant equity interest in the PNG LNG venture in Papua New Guinea. Santos also operates gas fields offshore WA that supply the domestic market, and produces gas, condensate and liquids from its onshore Cooper Basin business in South Australia (SA). Santos has diversified its production portfolio through the merger with Oil Search in 2021. Santos will start gas production later this year from the CO_2-laden Barossa gas field.

APA Group, Australia's largest gas infrastructure company, operates transmission and distribution networks, and a gas-fired power plant. Australia's gas transmission and distribution networks make up an estimated 7% of methane emissions from Australia's oil & gas sector.[1] Most of APA's methane emissions are from pipeline leaks.

Oil & gas companies are prioritising growth over abatement

Despite commercially available abatement options, APA, Woodside and Santos continue to prioritise growth projects that are likely to increase their methane emissions. APA's and Woodside's emissions have both grown since 2020. While Santos's reported methane emissions have fallen, this likely reflects (at least in part) declining production.

This is despite methane abatement making financial sense. Both the International Energy Agency (IEA) and Rystad Energy state that most of Australia's oil & gas methane emissions could be cost-effectively abated.[2,3] In part, this reflects methane's inherent value to these companies given it can be used to power their operations or sold to other gas users. APA, Woodside and Santos are potentially forgoing the benefits of capturing and using methane emitted through their operations.

These companies also continue to rely on emission factors to estimate their methane emissions rather than direct measurement, raising the possibility of underreporting. All three companies have undertaken studies to better understand their emissions, but the lack of detail on specific approaches used, and the timing, duration and location of these studies make it hard for investors to assess the risk and impacts of any underreporting.

Investors also lack sufficient detailed guidance on each company's proposed methane abatement actions, including approach and timing by facility.

Coal mining overview

BHP and Whitehaven Coal

Coal companies are not making progress on methane, with little to no abatement action, and strong growth plans driving increases.

BHP is a diversified mining company but retains significant thermal and metallurgical coal mining assets in Australia, and is seeking approval to continue mining coal beyond 2100. BHP's coal mining assets are housed in two distinct business units. Metallurgical coal assets are owned by the BHP Mitsubishi Alliance (BMA), comprising BHP (50%) and Mitsubishi Corporation (50%). These assets are based in Queensland (QLD) and consist of open-cut coal mines (Caval Ridge, Peak Downs and Saraji), and an open-cut and underground mine complex comprising Goonyella Riverside and Broadmeadow. BHP also wholly owns the largest open-cut coal mine in New South Wales (NSW), Mount Arthur, which produces thermal coal.

Whitehaven is a pure play Australian coal company. Prior to acquiring the Blackwater and Daunia mines, it almost entirely produced thermal coal (95% in FY2023). With the Daunia and Blackwater acquisition in April 2024, Whitehaven now also produces coking coal and pulverised coal injection (PCI) coal, by volume 58% in the first half of FY2025.

Both companies produce most of their coal from open-cut mine operations – about 90%. However, neither company has undertaken any methane abatement at their open-cut mines. Without implementing structural abatement, and with expansions in production proposed, the remaining emissions reduction options for these companies to meet their greenhouse gas (GHG) targets would rely largely on purchasing carbon offsets. The rising cost of carbon credits forecast in Australia could therefore increase coal miners' operating costs. Other options to target Scope 1 emissions include only reducing CO_2 emissions (for example, by electrifying diesel equipment), making changes to methane emissions reporting or reduction baselines, redesigning mine plans to avoid high gas zones or deeper coal seams, or reducing production.

The emissions intensity of open-cut mines varies widely. Companies may wish to target open-cut operations that have higher methane intensity first, before moving on to the less methane-intensive mines in their portfolio.

A change in methods to estimate open cuts' methane emissions has coincided with a slump in self-reported emissions.

Given that independent sources such as the IEA indicate open-cut emissions could be three times higher than reported, these decreases could be exacerbating underreporting risks for companies. According to ClimateTRACE, emissions could be even higher than reported: three times higher for Blackwater; five times higher for Peak Downs, Saraji and Mount Arthur; six times higher for Caval Ridge; and 13 times higher for Whitehaven's Maules Creek.[4]

Both companies are also missing an opportunity to show leadership in abatement at underground mines. At BHP's Broadmeadow mine, the only abatement occurring is the minimum pre-drainage mandated by the state government. Whitehaven recently stated that multiple fugitive emissions abatement projects are under way or under investigation at its Narrabri site, but to date there is no public record of pre-drainage or other methane abatement actions there.[5] This is despite numerous examples in the industry of underground mines capturing and utilising methane gas in onsite power stations or distributing methane for gas sales.[6]

Underground coal mines already have a range of methane abatement options available to them, with enhancing pre-drainage a practical first step to capture methane. This is because pre-drainage already occurs in most underground mines, and the methane captured is usually in higher concentrations that can be sold or utilised more easily. This can provide additional safety benefits by lowering overall methane emissions during underground mining operations, and reducing outburst or fire risks that can cause harm to workers and losses in production.

Key questions investors could ask companies

Reporting risks	Stated targets risks	Expansion plans risks	Abatement action risks	Methane costs
• How do your self-reported emissions compare against other independent sources such as the IEA, ClimateTRACE and OpenMethane? If they differ, what are the reasons for this? • Are you directly measuring and monitoring methane emissions? Which methods are you currently using and why aren't you using higher-order methods? • Are you seeking independent and expert advice or review on the estimation methods you use? If not, why not? • What steps are you taking to improve methane estimation methods? How can you tell these changes are leading to improved accuracy in estimation of emissions? • Are you using independent atmospheric verification methods, e.g. from satellite data or aerial surveys? If not, why not? Do you plan to use them in the future? If so, when?	• If you do not have both specific short- and long-term GHG and methane reduction targets, why not? • Are you on track to meet your interim and net zero GHG and/or methane reduction targets? • How would your GHG and/or methane targets be affected if changes to estimation methods increased your reported emissions? • How do you plan to achieve your GHG or methane targets? How much are they being met via: reporting changes (such as a switch from Method 1 to Method 2 for open-cut coal mine emissions estimation methods); carbon offsets; structural methane abatement; or reduced production? • Have you conducted structural methane abatement or reduced production to meet your targets? If not, why not?	• Is decreasing production part of your GHG reduction strategy to 2030 or 2050? If not, why not? • Will your expansion plans increase your methane emissions? If yes, please provide best estimates on how much. • Do you provide guidance on modelled emissions, by gas, for each new growth project? If not, why not? • How do you propose to manage and structurally abate methane from your stated expansion plans? • How will your expansion plans affect your GHG and/or methane reduction targets in the short and long term?	• What specific actions are you taking to reduce methane emissions at each of your facilities (such as open-cut coal mines or LNG liquefaction plants)? • Do you provide detailed information on specific actions you have taken and will take to reduce methane emissions by facility? If not, why not? • **Open-cut coal mines:** Why have you not engaged in methane abatement at your open-cut operations? Please provide details of any steps you have taken, what barriers are you facing, and what are you doing to overcome them? • **Underground coal mines:** Why have you not rolled out abatement technology at your underground operations, such as enhancing pre-drainage before mining, improved housekeeping or VAM abatement? What barriers are you facing, and what are you doing to overcome them? • **Oil & Gas:** What specific abatement action, such as equipment upgrades, have you implemented to reduce methane emissions, at which facilities, and what is the likely volume of abatement? • **Oil & Gas:** Will you implement best-practice equipment and processes for all new growth projects, or if not, why not? Please provide details of any planned actions, including likely volumes of abatement.	• Have you conducted a comprehensive cost-benefit analysis (CBA) on methane abatement for each of your projects or facilities? If not, why not? If yes, what were the results? • Are there barriers impeding your ability to capture and sell methane for additional revenue? What are you doing to overcome these barriers?

Introduction

Methane emissions must be addressed to achieve global climate goals and mitigate economic losses. On its current trajectory, global warming is forecast to cause a 16.5% decrease in Australia's GDP by 2048.[7] Methane has a short atmospheric life and stronger warming potential than carbon dioxide (CO_2), meaning methane abatement can provide benefits relatively quicky. The International Energy Agency (IEA) has stated that targeting a reduction in fossil fuel methane emissions has the most potential to rapidly reduce overall methane emissions globally.[8]

Methane's global warming potential, along with growing public awareness and scrutiny of methane emissions from fossil fuels, creates social licence risks for fossil fuel producers.[9] This is particularly relevant for gas companies given their claims that gas is a cleaner energy source than coal and a crucial fuel for the energy transition.[10] Coal miners' strategies to increase metallurgical coal mine production could carry additional risk given Australian metallurgical coal is 40% more methane-intensive on average than thermal coal.[11]

Methane poses risks to investors because limitations with current reporting methods mean exposure to climate-related risks in their oil & gas and coal mine portfolios could be higher than currently anticipated. The Institutional Investors Group on Climate Change notes that "Not only does this inhibit their ability to design optimal, cost-effective abatement strategies, it leaves them exposed to reputational and legal risks associated with inaccurate reporting."[12] With the climate-related disclosure framework having come into effect in 2025 in Australia, greater attention will also be paid to companies' greenhouse gas (GHG) reporting methods over the next few years. State and federal governments may also implement more stringent regulations to drive down methane emissions.

Investing in capturing greater volumes of fugitive methane could also present financial opportunities to companies. However, most Australian fossil fuel companies are lagging on methane abatement action, despite the technological and strategic solutions available.

IEEFA's previous report discussed the high uncertainty around methane reporting, and the potential for methane emissions to increase from proposed coal mine and oil & gas developments in Australia.[13] The research found that, by not capturing and selling fugitive methane, Australian fossil fuel companies are potentially forgoing about AU$933 million of value every year, subject to gas price movements.

The report also found that approximately two thirds of methane emissions from the oil & gas and coal mining sectors could be abated through mature technologies, at a cost below AU$30 per tonne (t) of CO_2 equivalent (CO_2e). IEEFA found that about 90% of oil & gas methane emissions could be reduced at no net cost overall, and 59% of methane emissions could be abated from coal mining at an average cost of AU$1/t of saleable coal across the industry.

However, the companies examined in this report have committed zero or limited capital allocation or targets specifically to address methane emissions. This means the large pipeline of proposed coal and gas developments could worsen methane emissions. Currently the lack of transparency and reliability in companies' self-reported methane emissions makes it harder to develop a business case for methane abatement.

This analysis focuses on five companies: Woodside, Santos and APA Group in oil & gas; and BHP and Whitehaven, two of Australia's largest coal mining companies. The report provides a methane exposure risk assessment of each company based on reporting risks; stated targets; expansion plans; abatement actions taken; and methane costs incurred by companies. These indicators all affect companies' exposure to risks regarding their climate targets. Methods used to calculate these risks are discussed throughout the report and fully referenced, with a separate technical appendix and data file available on request.

Reporting Risks

Mandatory reporting changes will improve transparency, but large underreporting risks remain.

APA	Woodside	Santos	BHP	Whitehaven
Low	Moderate	Moderate	High	High

IEEFA reviewed the five companies' reporting methods and analysed the risk posed by the accuracy, transparency and planned improvements to current methane reporting methods. Accuracy refers to the risk that methane emissions are underreported. Transparency refers to the degree of completeness, detail and availability of data. Planned Improvements refers to the stated changes to reporting that would improve accuracy or transparency. We found all five companies had poor scores for reporting accuracy, with slightly better scores on transparency and planned improvements to reporting measures.

Australia's mandatory climate-related financial disclosures requirements, which came into effect on 1 January 2025, will change the reporting requirements for these companies. This means they are required to report the following:

Scope 1 and 2 emissions using methodologies consistent with the National Greenhouse and Energy Reporting (Measurement) Determination 2008, from 1 July 2027 onwards.

Scope 3 emissions relating to one-year periods occurring up to 12 months prior to the relevant reporting year, from 2026 onwards.

Individual GHG emissions volume, meaning they'll have to report estimated methane emissions and CO_2 emissions separately.

This is an emerging space, and companies will be granted a three-year grace period for reports they issue between 1 July 2025 and 30 June 2028, and for any errors in their sustainability reporting concerning Scope 3 emissions or climate-related, forward-looking statements. However, the regulator will still be able to bring action for breaches of relevant provisions from 2025. After this period, regular liability arrangements will apply.[14]

While these changes will improve reporting transparency, they do not address underreporting risks facing these companies.

Questions investors could ask companies

- How do your self-reported emissions compare against other independent sources such as the IEA, ClimateTRACE and OpenMethane? If they differ, what are the reasons for this?
- Are you directly measuring and monitoring methane emissions? Which methods are you currently using and why aren't you using higher-order methods?
- Are you seeking independent and expert advice or review on the estimation methods you use? If not, why not?
- What steps are you taking to improve methane estimation methods? How can you tell these changes are leading to improved accuracy in estimation of emissions?
- Are you using independent atmospheric verification methods, e.g. from satellite data or aerial surveys? If not, why not? Do you plan to use them in the future? If so, when?

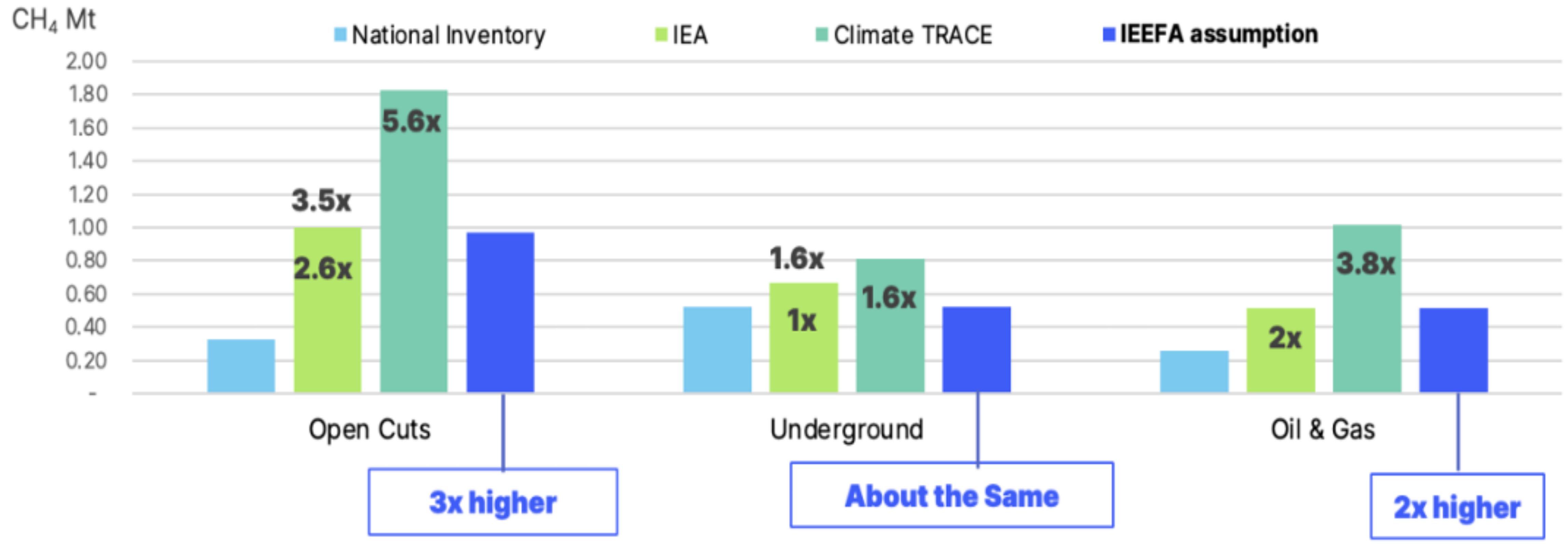
Companies risk underreporting methane emissions by relying on production-based emissions factors

All companies examined in the report rely on production factors to estimate their methane emissions following the methods laid out in the National Greenhouse and Energy Reporting Scheme (NGERS).

However, the Climate Change Authority (CCA) has noted that approaches based on emissions factors may be inherently less accurate than higher-order approaches centred on direct measurement of methane emissions.[15] The CCA recommended developing new higher-order methods where none are available, such as some sources of venting in oil & gas production. It also recommended developing guidelines for top-down measurements, such as satellite monitoring and remote sensing, to be used to verify production-based 'bottom-up' estimates.[16] These recommendations reflect the significant risk of bottom-up methodologies delivering inaccurate methane emissions estimates, and the critical importance of top-down verification.

Australia's national inventory data reports fossil fuel methane emissions at 845 million tonnes (Mt) of methane (CH_4) in 2022. However, according to data available from the IEA, this figure could be more than twice as high, at about 2,182Mt of CH_4[17]. Assuming underground coal mine methane emissions are as reported, this would mean open-cut coal mine methane emissions could be three times higher than reported.

Figure 1: IEEFA estimates of methane emissions underreporting



Sources: Department of Climate Change, Energy, the Environment and Water (DCCEEW); IEA; ClimateTRACE; IEEFA.

Note: The IEA does not report on underground and open-cut mine methane estimates separately; IEEFA considered a range of underreporting factors based on underground emissions varying between reported levels and ClimateTRACE levels.

Oil & gas methane emissions could be two times higher than reported

Australia's oil & gas sector's self-reported estimates do not align with recent estimates developed by independent research organisations, such as the IEA, which suggest that methane emissions from oil & gas production in Australia could be double self-reported estimates.

This disparity likely reflects several factors, including the use of emissions factors, rather than comprehensive direct measurement and verification, to estimate fugitive methane emissions. "Super-emitter" events (i.e. large unanticipated emission events due to equipment and process failures, such as pipeline leaks and improperly capped wells) will not be reflected in emission factor-based estimates.[18]

The lack of availability of higher-order estimation methods for some oil & gas activities under the NGERS is also likely to fuel the risk of underreporting, to the extent that it limits the ability of companies to use more accurate higher-order methods. Ageing infrastructure can also magnify these risks given methane leaks can be relatively common from older oil & gas infrastructure.[19]

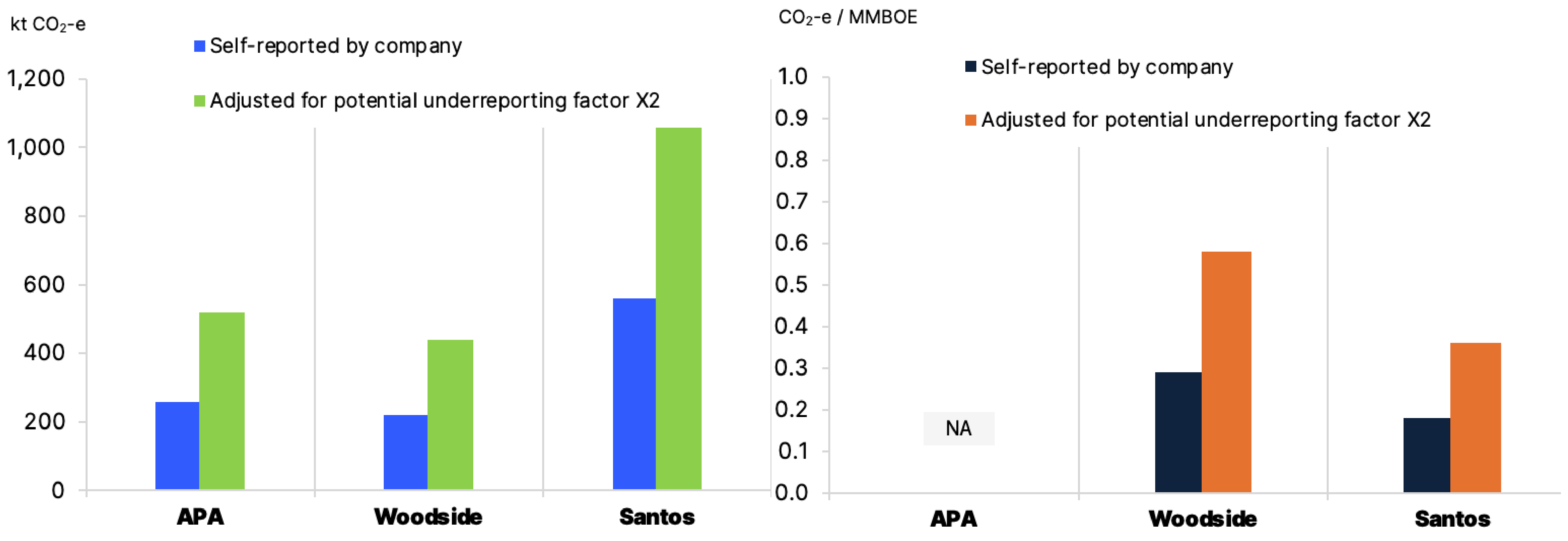
This is a key risk for Woodside, Santos and APA, which all have ageing infrastructure. These companies have undertaken steps to improve their methane emissions measurement and reporting.

In 2018, Santos entered into a 10-year agreement with the Commonwealth Scientific and Industrial and Research Organisation (CSIRO) to undertake baseline and background methane monitoring at onshore Santos operations in Australia.[20] It also implemented an ongoing leak detection and repair regime to identify sources of methane emissions, which includes continuous monitoring of gas plant equipment.[21]

Woodside has similarly sought to improve its methane measurement through the use and trialling of a range of technologies, including spectrometric aerial monitoring, satellite-based detection, drone surveys and optical gas imaging.[22] It has also developed a database of methane emission sources within its portfolio, but this has not been made publicly available.[23]

APA has also undertaken methane measurement surveys of key infrastructure, including the Goldfields Gas Pipeline (GGP) and South West Queensland Pipeline (SWQP).[24] Further, the latter survey identified that actual methane emissions may be higher than those estimated using emissions factors (under Method 1 in the NGER scheme).[25]

Figure 2: Fugitive methane emissions (LHS) and methane intensity calculated from self-reported emissions (RHS) by company, FY2024



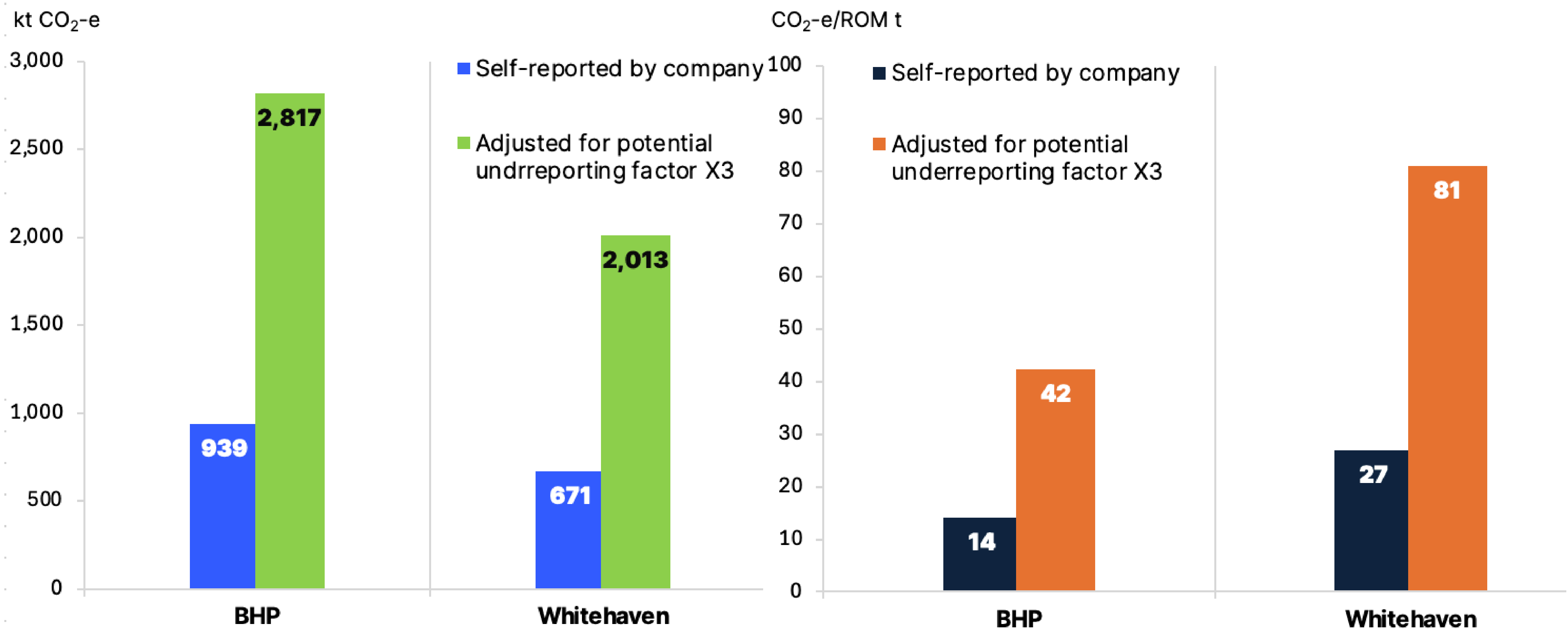
Sources: IEEFA; APA; Woodside; Santos.

Open-cut emissions could be three times higher than reported, making BHP and Whitehaven's underreporting risk very high

Both BHP's and Whitehaven's overall underreporting risk is categorised as high due to the prevalence of open-cut coal mine operations, use of lower-order estimation methods, and a lack of independent verification. BHP produces 93% of its run-of-mine (ROM) coal (on 100% operational basis) via open-cut mining methods, and Whitehaven about 85%.

It should be noted BHP and Whitehaven's reported emissions refer to emissions accounting on a 100% basis for joint ventures where operational control is held, irrespective of equity interest. BHP includes both its metallurgical coal assets, in which it holds a 50% stake, as well as its NSW energy coal asset Mount Arthur, which is 100% owned by BHP.

Figure 3: Fugitive methane emissions (LHS) and methane intensity calculated from self-reported emissions (RHS) by company, FY2024



Sources: IEEFA; BHP; Whitehaven.

Methods to estimate coal mine methane (CMM) emissions

As part of a review of the NGERS framework, the CCA recommended phasing out Method 1 and urgently reviewing Method 2 for estimating fugitive emissions in open cut coal mines, in favour of more accurate higher-order methods.[26]

Open-cut coal mines can use Method 1, 2 or 3 set out in the NGERS to estimate methane intensity per tonne of ROM coal produced. This produces their annual fugitive emissions estimate.

Method 1 uses a set emissions factor of 0.031 for all QLD mines and 0.061 for all NSW mines. Using a standard emissions factor for all mines in QLD and NSW ignores critical factors that are proven key determinants of the rate and volume of methane emissions from open cuts. These include the depth of mining, the gas content of individual seams, and the methane proportion in the gas.

Method 2 requires miners to use gas content samples to calculate an emissions factor. However, there is no independent review required under Method 2.

Method 3 is the same as Method 2 but requires miners conduct the gas sampling process in accordance with outdated Industry standards.

BHP emissions decreased 96% after a switch to Method 2 reporting, meaning underreporting risks might worsen

BHP produces 93% of its ROM coal (on 100% operational basis) via open-cut mining.[27] It previously used Method 1 to estimate methane emissions from all of its open-cut operations subject to the Safeguard Mechanism (SGM). More recently it switched to Method 2, which coincided with a 96% overall decrease in reported emissions. This excludes the combined Goonyella Riverside and Broadmeadow complex as its emissions are not reported separately.

Figure 4: BHP open-cut mine emissions reporting Method 1 v Method 2

		Emissions Factor ($KtCO_2$-e/ROM t)		Production (ROM Mt)	Fugutive Emissions ($KtCO_2$-e)		
		METHOD 1	METHOD 2		METHOD 1	METHOD 2	RATIO
BHP	Mount Arthur	0.061	0.0018	21	1,293	**39**	33x
BMA	Peak Downs, Saraji, Caval Ridge	0.031	0.0014	40	1,240	**55**	23x
BHP Operational control Open Cut Mines				**61**	**2,533**	**94**	**27x**

Due to the underreporting risk at open-cut operations, the decrease in self-reported methane emissions by changing estimation methods could worsen the underreporting risks for BHP and Whitehaven.

A change in reporting method at BHP's Caval Ridge and Saraji South mines coincided with significant drops in reported emissions from both sites between FY2021 and FY2024.[28] Peak Downs and Mount Arthur had moved to Method 2 prior to FY2020. When Mount Arthur changed from Method 1 to Method 2, its fugitive methane emissions intensity fell significantly. Its calculated emissions intensity is now 33 times lower than the NSW emissions factor of 0.061 tonnes of CO_2 equivalent (tCO_2e) per ROM tonne of coal under Method 1.

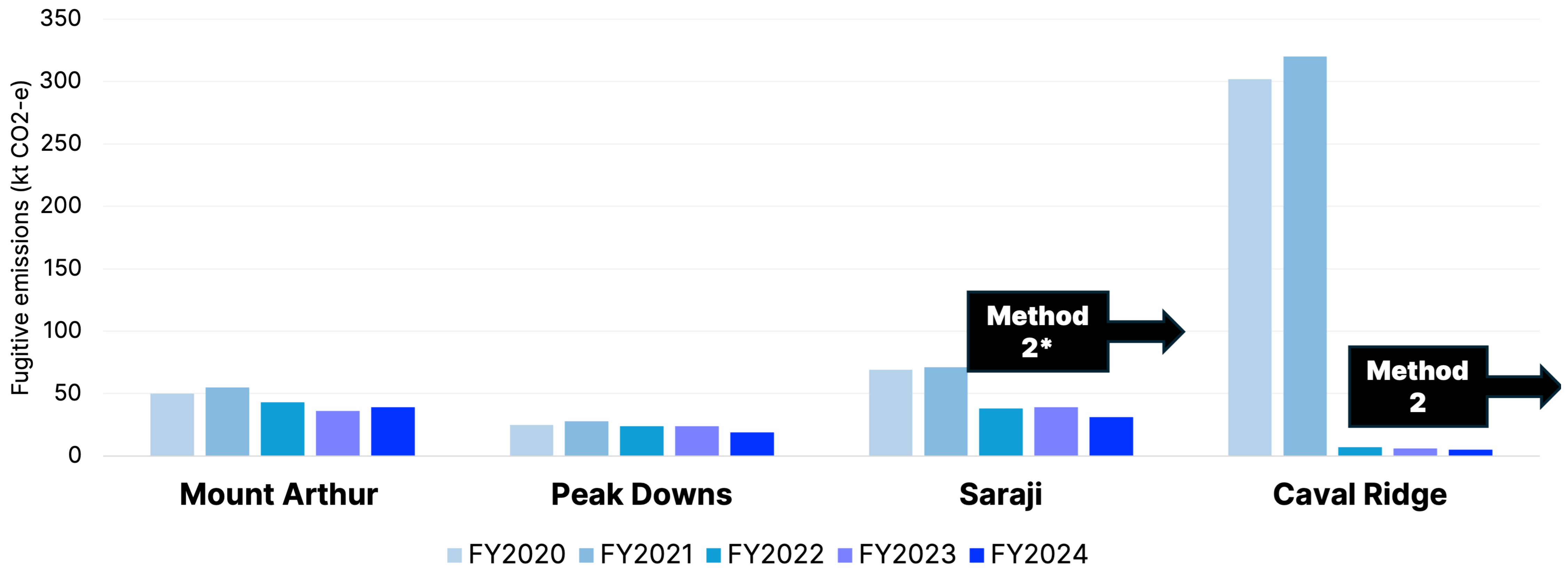
After Whitehaven switched from Method 1 to Method 2 at its Maules Creek mine in FY2021, reported Scope 1 emissions fell by about 64%.

BHP states that it adjusts its baseline and reporting years to account for acquisitions, divestments and methodology changes.[29] **Although Caval Ridge reported a 98% reduction in Scope 1 emissions after switching to Method 2 in FY2022, its baseline under the SGM increased 21%** (113,212tCO^2e) between FY2019 and FY2021, a compound annual growth rate (CAGR) of 5%. SGM baselines are intended to decrease to 2030 by about 4.9% a year. It is unclear why Caval Ridge's SGM baseline increased.

Caval Ridge's baseline number is not reported publicly between FY2019 and FY2021.[30] Saraji's baseline remained constant between FY2017 and FY2020, but has not been reported since, so it is unclear whether the switch to Method 2 has resulted in a change in its SGM baseline.

Caval Ridge is not the only coal mine to increase its SGM baseline. SGM baselines can be readjusted upwards, usually due to changes in methane emissions reporting or estimations that result in an increase in emissions, rather than a decrease. Overall, there was a net increase in total coal mining baselines under the SGM of 261,475tCO_2e between FY2017 and FY2023.[31] In the same period there was a net decrease in all other SGM facilities (excluding coal mines and oil & gas facilities) of almost 7$MtCO_2e$.

Figure 5. BHP fugitive emissions (CO_2 and CH_4) trend for open-cut only coal mines



Sources: IEEFA; BHP.

Note: Saraji fugitive emissions decreased due to coal extraction occuring at less methane intensive areas of the mine. In FY2023 to FY2024 Saraji South changed from reporting using Method 1 to Method 2, contributing to the decrease in fugitive emissions

Stated Targets Risks

There is room for all companies to set stronger targets for GHG reduction, including setting specific methane targets.

APA	Woodside	Santos	BHP	Whitehaven
Low	High	High	High	High

All five companies have stated GHG reduction targets, but only APA has a specific methane reduction target (although Woodside and Santos have "aspirations" to reduce methane emissions). APA expects that meeting its methane target will contribute 30%-40% of the abatement required to meet its overall gas infrastructure emissions reduction target.[32]

All five companies have interim GHG reduction targets for 2030, and APA and Santos have net zero targets (by 2050). Woodside does not have an explicit net zero target, but has stated its ambition to reach net zero by 2050. In contrast, the other companies' targets refer to a reduction in CO_2e, made by reducing either CO_2 or methane emissions, or potentially through the use of carbon offsets, although this will depend on whether company-specific GHG targets are expressed in gross or net terms.

BHP has stated that it doesn't want to rely on offsets. However, the lack of structural abatement actions at its open-cut coal mine operations, combined with its expansion plans for these projects, means the company would have to rely on offsets to achieve emissions reductions.

In IEEFA's opinion, these targets could be more ambitious. The IEA, in its Net Zero Emissions scenario, finds that a 75% reduction in fossil fuel methane emissions will be required to limit global warming to the Paris Agreement target of 1.5°C above pre-industrial levels; a 40% reduction would be required under the 1.7°C scenario.[33]

Santos and Woodside are signatories to global methane reduction initiatives such as the Methane Guiding Principles and Aim for Zero Methane Emissions initiative. However, IEEFA is not aware of either company providing guidance on timings for disclosing independent, externally verified methane emissions estimates, on an absolute and intensity basis – consistent with Oil & Gas Methane Partnership 2.0 (OGMP 2.0) level 5. OGMP 2.0 is a voluntary methane emissions reporting framework, under which signatories commit to comprehensive methane emissions measurement and reporting.[34]

Despite commitments made in 2022, Woodside's methane emissions have actually increased since then. Neither APA, Woodside nor Santos have disclosed detailed plans for how they will reduce methane emissions – specifically by source, and on prioritisation and coverage, as recommended by the Institutional Investor Group on Climate Change.[35]

Questions investors could ask companies

- If you do not have both specific short- and long-term GHG and methane reduction targets, why not?
- Are you on track to meet your interim and net zero GHG and/or methane reduction targets?
- How would your GHG and/or methane targets be affected if changes to estimation methods increased your reported emissions?
- How do you plan to achieve your GHG or methane targets? How much are they being met via: reporting changes (such as a switch from Method 1 to Method 2 for open-cut coal mine emissions estimation methods); carbon offsets; structural methane abatement; or reduced production?
- Have you conducted structural methane abatement or reduced production to meet your targets? If not, why not?

Figure 6: Methane-specific emissions reduction target details by company

Company	Sector	Units	Methane Target	Baseline	Progress
Coal Mining					
BHP	Mid Term emissions Operational Scope 1 & 2 emissions	Scope 1& 2 emissions $MtCO_2$-e	30% reduction by FY 2030	FY 2020	FY2024 reported operational GHG: 9.2 $MtCO_2$-e (-32% cf FY2020)
	Long term emissions	Scope 1& 2 and Scope 3 emissions MtCO2-e	Net Zero 2050		
	Steel Tech		Support industry to develop steel production technology capable of 30 per cent lower GHG emissions intensity	relative to conventional blast furnace steelmaking[3]	
Whitehaven	Company (managed operations)	Net Scope 1 emissions $MtCO_2$-e	32% reduction by FY 2030	FY2023	
Oil & Gas					
APA	Gas Infrastructure operational emissions	Scope 1 methane emissions kt CH_4/ kt CO_2-e	30% reduction by 2030[1]	FY 2021	FY2024 methane emissions: 256 kt CO_2-e (+14% from FY21)
	Gas Infrastructure operational methane emissions	N/A	No methane abatement target	FY2021	FY2024 GHG: 544 kt CO_2-e (-5% from FY2021)
woodside	Company (net equity)	N/A	No methane abatement target	2016-20 (average emissions – 6.32 Mt CO_2-e)	CY2023: 5.532 Mt CO_2-e (-12.5% from base)
Santos	Company (equity share of emissions)	Scope 1 & 2 GHG emissions $MtCO_2$-e	30% absolute & 40% GHG emissions intensity reductions by 2030	FY2020 (Santos and Oil Search)	FY2023 GHG emissions: 4.73 $MtCO_2$-e (-20% from FY20)

Sources: BHP; Whitehaven; APA; Woodside; Santos.

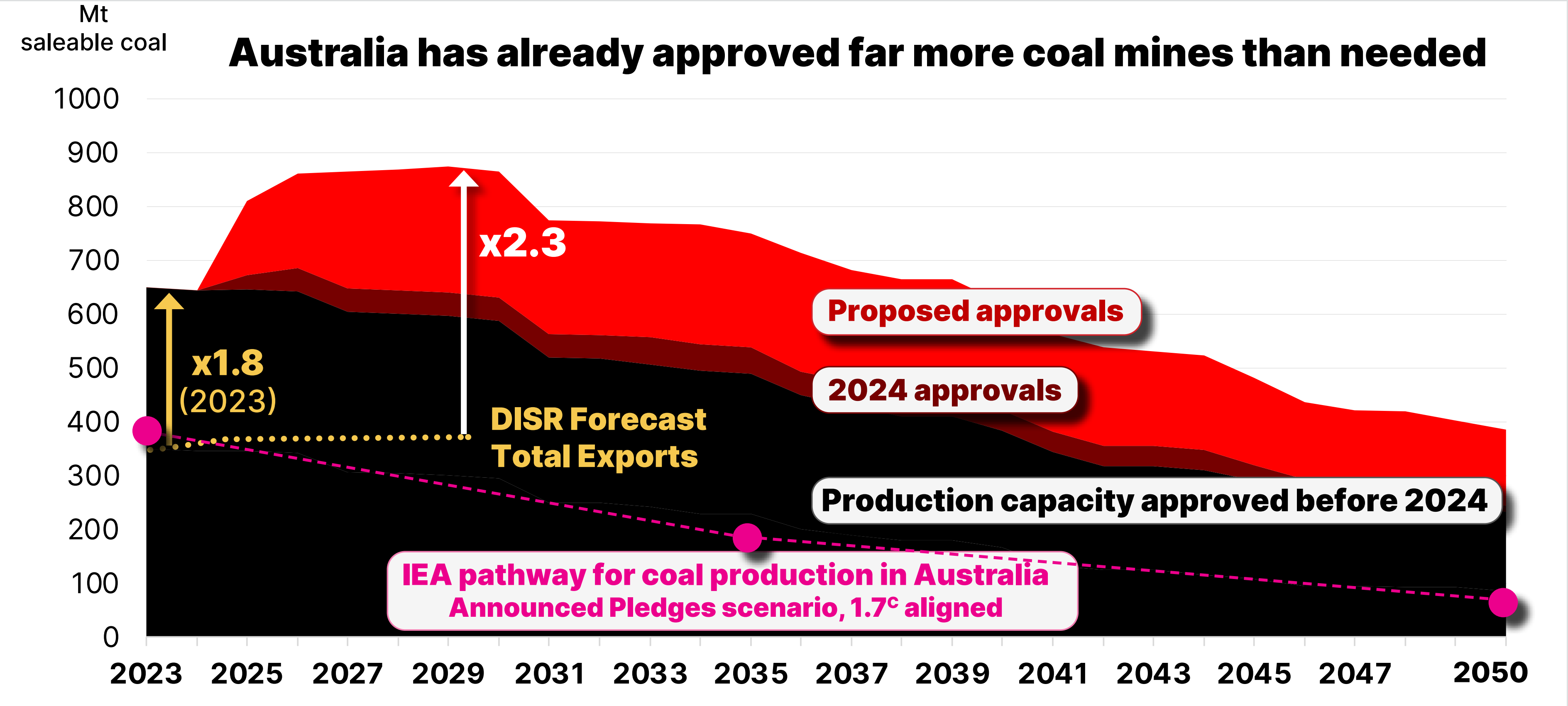
Expansion Plans Risks

Expanding fossil fuel production will increase methane emissions unless proven and effective abatement activities are implemented.

APA	woodside	Santos	BHP	Whitehaven
High	High	High	High	High

BHP and Whitehaven both have significant expansion plans, with Whitehaven looking to double production capacity by 2050, and both companies applying for mining to be approved beyond the year 2100. Recent IEEFA analysis highlights the high level of uncertainty surrounding methane emissions associated with proposed coal mine expansions.[36] Additionally, Australia already has capacity to increase coal production under current mining approvals without additional expansions. Approved saleable coal production capacity was 1.8 times higher than actual export volumes in 2023.[37]

Figure 7: Australian production capacity saleable coal (approved and proposed) vs export forecasts



Sources: IEEFA; Department of Industry, Science and Resources (DISR); IEA; EPBC.
Note: Saleable coal production capacity is assumed at 80% of ROM production capacity.

In the oil & gas space, APA, Woodside and Santos have all flagged future growth projects that could affect their methane emissions (for example, see Page 19).

Santos has noted its aim to increase oil & gas production from 87.1 million barrels of oil equivalent (mmboe) in 2024 to between 90 and 97mmboe in 2025, and to more than 100mmboe from 2026.[38, 39] This equates to a production rise of 14.1% in about two years.

Woodside also has a growth focus, having recently acquired the Driftwood LNG project in the US. If sanctioned, it could have a capacity as high as 27.6 million tonnes per annum (Mtpa) based on existing approvals.[40] Woodside is also developing the Scarborough and Trion projects, which will materially increase its gas, LNG and oil production.[41]

Questions investors could ask companies

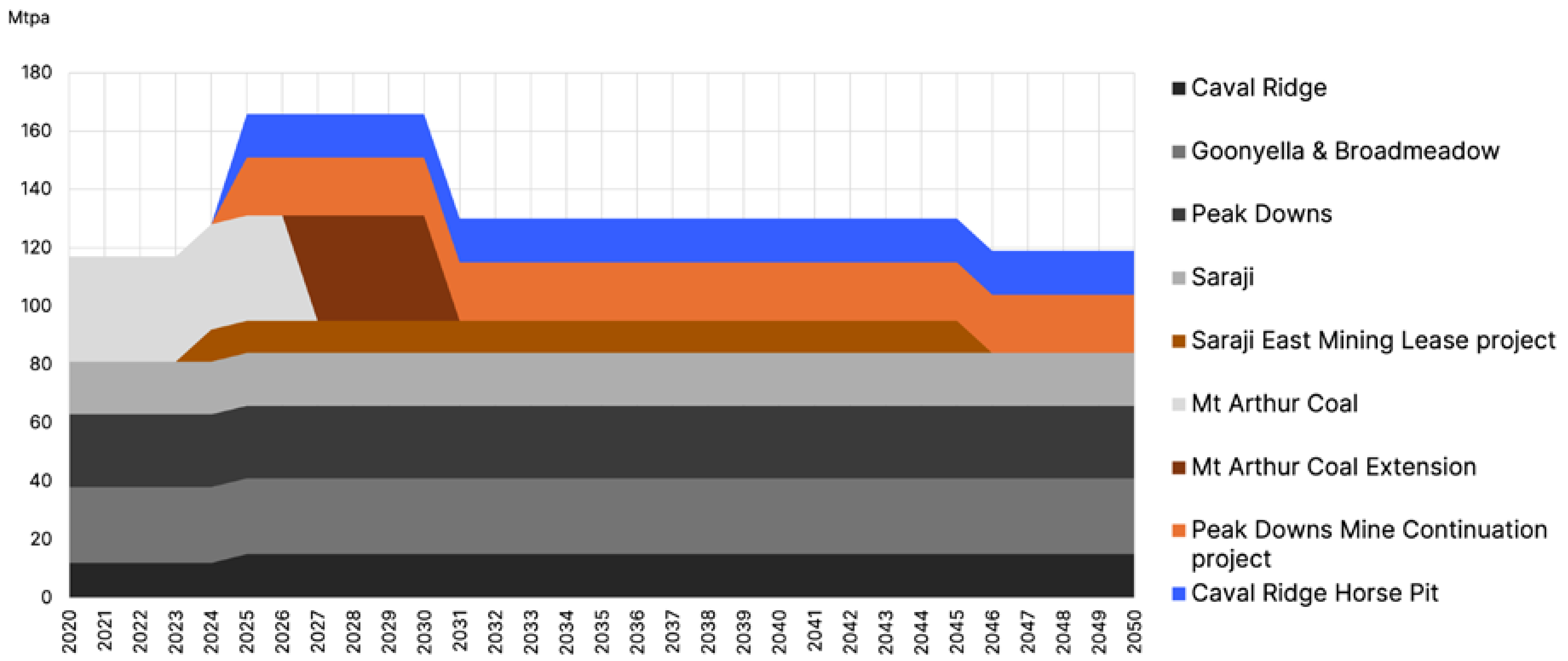
- Is decreasing production part of your GHG reduction strategy to 2030 or 2050? If not, why not?
- Will your expansion plans increase your methane emissions? If yes, please provide best estimates on how much.
- Do you provide guidance on modelled emissions, by gas, for each new growth project? If not, why not?
- How do you propose to manage and structurally abate methane from your stated expansion plans?
- How will your expansion plans affect your GHG and/or methane reduction targets in the short and long term?

BHP plans long-term unabated coal production

BHP has proposed significant coal mine expansion plans in Australia. It recently had its Caval Ridge expansion project approved under the Environment Protection and Biodiversity Conservation (EPBC) Act, granting approval to mine up to 15Mtpa until 2056. The company also proposes an expansion at Peak Downs to produce up to 25Mtpa ROM coal until 2116, and two projects at its Saraji mine including an expansion to the open-cut mine and a new greenfield underground mine development. Additionally, BMA was granted approval in 2015 for the Red Hill project to build a new underground mine near its existing Goonyella Riverside mine. The project remains valid until 2052, but at the time of writing it remains undeveloped.

In addition to planned expansions in its mostly metallurgical coal mines, BHP is also seeking to extend thermal coal mining at Mount Arthur, the largest open-cut coal mine in NSW's Hunter Valley, which is wholly owned by BHP.

Figure 8: Capacity of approved and proposed coal mines where BHP holds an ownership interest, 2020-2050



Sources: IEEFA; BHP; EPBC documents

These expansions and new mine proposals are in contrast to an earlier statement by BHP, in which it said would not develop any mine expansions in QLD, following the rise in royalty rates.[42]

Figure 9: BHP's Australian coal mines, operating and proposed expansions

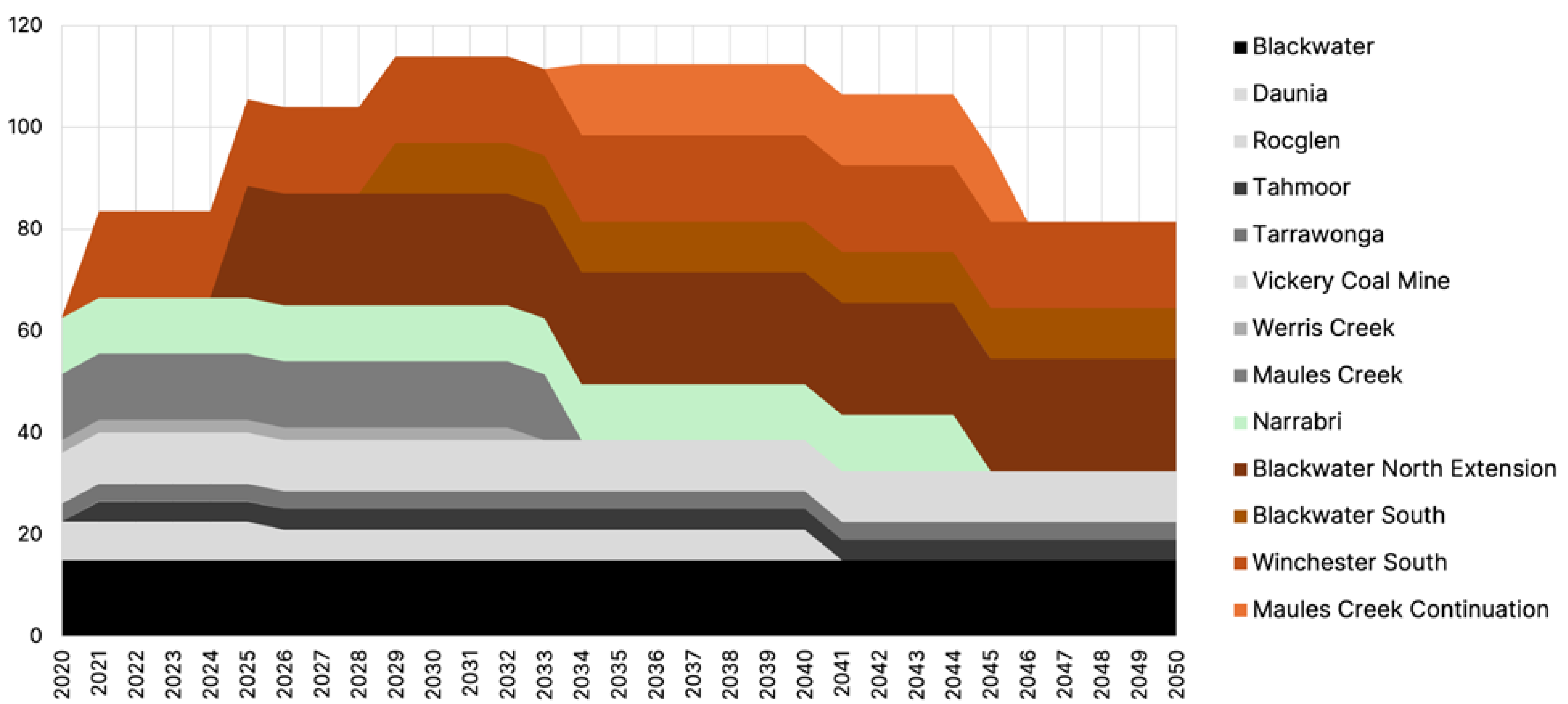
Mine Name	Location	Mine Type	Coal Type	Extension Proposal
Goonyella Riverside & Broadmeadow (50%)	QLD, Bowen	Open Cut & Underground	Metallurgical	Brownfield – Expansion Red Hill Project
Caval Ridge (50%)	QLD, Bowen	Open Cut	Metallurgical	Brownfield - Extension APPROVED
Peak Downs (50%)	QLD, Bowen	Open Cut	Metallurgical	Brownfield - Expansion
Saraji Mine (50%)	QLD, Bowen	Open Cut	Metallurgical & PCI	Brownfield - Expansion
				Greenfield - Saraji East Project
Mt Arthur Coal (100%)	NSW, Hunter	Open Cut	Thermal	Brownfield Extension

Sources: BHP[43]; DCCEEW[44].

Whitehaven proposes to increase coal production capacity by ~60% to 2050

Whitehaven has significant expansion plans. Its Narrabri Underground Stage 3 project was approved under the EPBC Act in September 2024. As reported by IEEFA, according to the NSW IPC 2022 report on the Narrabri South extension, "beyond 2032 methane emissions will increase to about double current levels (i.e. 30% to 40% CH_4 [methane] compared with 5%-25% in the northern [existing] mine)".[45] As the mining projects extend into deeper and more gaseous reserves, this problem will only increase.

Figure 10: Capacity of approved and proposed coal mines where Whitehaven holds an ownership interest, 2020-2050



Sources: IEEFA; Whitehaven Coal; EPBC Act Public Portal (or EPBC documents)

Following approval of Narrabri South mine, Whitehaven awaits approval for new mines and expansions at Winchester South, Blackwater South and Blackwater Mine-North in QLD, and the Maules Creek Continuation Project in NSW. It has yet to ramp up its recently commenced Vickery mine in NSW.

Whitehaven's acquisition of Blackwater and Daunia in April 2024 increased its reported Scope 1 emissions by 5% in FY2024 from FY2023. In FY2025, Whitehaven will report on a full year of operations for both mines, which will likely significantly increase its reported Scope 1 emissions further.

Figure 11: Whitehaven's Australian coal mines, operating and proposed expansions

Mine Name	Location	Mine Type	Coal Type	Extension Proposal
Blackwater (100%)	QLD, Bowen	Open Cut	Metallurgical | Thermal	**Brownfield - Expansion**
Blackwater Mine - Blackwater South	QLD, Bowen	Open Cut	Metallurgical	**Greenfield**
Winchester South (X%)	QLD, Bowen	Open Cut	Metallurgical | Thermal	**Greenfield**
Daunia (100%)	QLD, Bowen	Open Cut	Metallurgical | PCI	No
Tarrawonga	NSW, Gunnedah	Open Cut	Metallurgical | Thermal	No
Vickery Coal Mine	NSW, Gunnedah	Open Cut	Metallurgical | Thermal	No /Approved, Ramp up to come
Werris Creek (100%)	NSW, Gunnedah	Open Cut	Thermal	No (now closed)
Narrabri (76%)	NSW, Gunnedah	Underground	Thermal	**Brownfield - Extension**
Maules Creek (75%)	NSW, Gunnedah	Open Cut	Thermal	**Brownfield - Extension**

Sources: Whitehaven Coal[46], DCCEEW[47]

APA, Santos and Woodside remain heavily weighted towards growth rather than methane abatement

All three oil & gas companies assessed in this report have significant growth plans, with capital allocation and executive remuneration frameworks that prioritise growth over climate objectives and methane emissions reductions.

APA has several gas growth projects, including an expansion to the east coast gas grid, but its proposed pipelines to connect the Beetaloo Basin to Darwin and to the east coast are the most material. These pipelines are likely to have significant emissions implications.

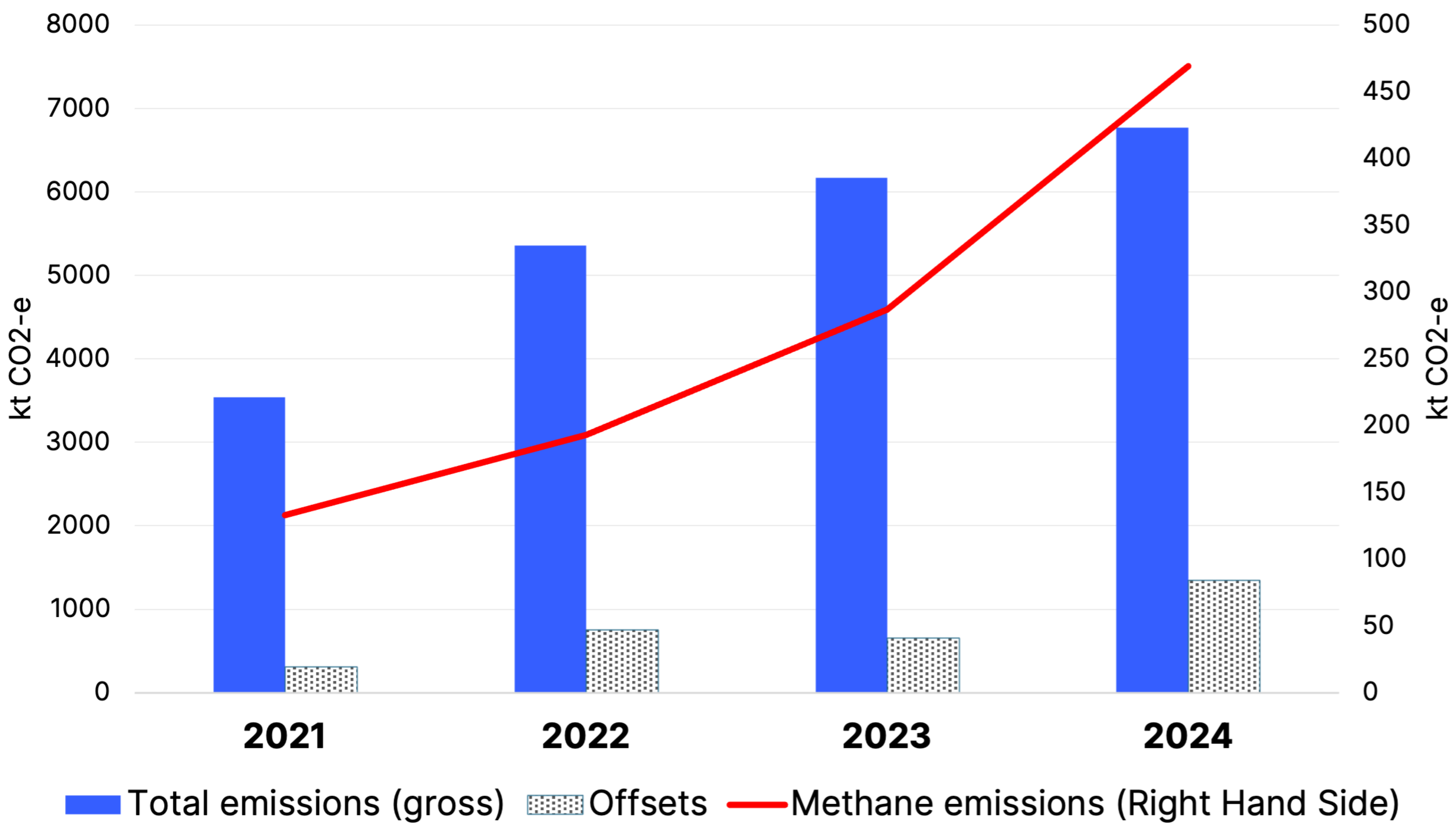
Climate Analytics found that the transmission of gas from the Beetaloo Basin to Darwin, where an LNG plant is to be built if Beetaloo gas is developed, could result in emissions of between 0.3MtCO_2e and 1MtCO_2e a year,[48] with methane accounting for 50%-100% of these emissions.[49] If this pipeline is developed, IEEFA estimates its methane emissions could account for 95%-318% of APA's 2030 methane emissions target (based on Climate Analytics analysis of the project's methane emissions and assuming methane emissions account for half of transmission emissions), and 39%-129% of APA's 2030 gas infrastructure emissions target.

Santos also has plans to increase production from new projects, including the Barossa and Pikka developments. Santos guidance indicates it plans to increase its production from 87.1mmboe in 2024 to more than 100mmboe from 2026. While IEEFA is not aware of any specific modelling of these projects' likely methane emissions, the historical correlation between Santos's methane emissions and production levels (see Figure 13 on page 22) suggests these projects will likely increase Santos's emissions.

Woodside's production has increased in recent years, reaching 193.9mmboe in 2024, and is likely to keep growing. The Scarborough project is slated to increase Woodside's LNG production capacity by 5Mtpa, which is equivalent to about 47mmboe (representing about 24% of Woodside's 2024 production).[50] Further, Woodside's proposed LNG facility in the US has a permitted capacity of 27.6Mtpa, which, if sanctioned, would surpass Woodside's 2024 production.[51]

These projects, if realised, would increase Woodside's methane emissions unless it is able to drastically lower its methane emissions intensity. Indeed, Woodside's recent growth and acquisitions have increased the company's methane emissions (and methane emissions intensity) materially since 2020 (Figure 12), which coincides with its increasing use of carbon offsets.

Figure 12: Woodside's methane emissions since 2021



Source: Woodside[52]

Abatement Actions Taken

All five companies have taken limited or no abatement action to date, despite mature abatement technologies available in both sectors.

APA	Woodside	Santos	BHP	Whitehaven
Moderate	Moderate	Moderate	High	High

Oil & gas companies across Australia have taken steps to reduce methane emissions through structural abatement, but more action is warranted. Steps taken so far by APA, Woodside and Santos largely relate to:

- Preliminary studies to support further action.
- Improved monitoring to facilitate better understanding of methane emission sources and available abatement opportunities.
- Installation of gas capture technologies to reduce venting and flaring.
- Replacement of equipment, such as seals, to reduce methane leaks.

Despite these actions, APA and Woodside's methane emissions are higher now than they were in 2020, and while Santos's methane emissions have fallen, this likely reflects declining production (see page 22).

In coal mining, BHP has so far only attempted methane abatement at its underground Broadmeadow coal mine by flaring drained methane. Flaring essentially combusts methane, turning it into CO_2 that is released into the atmosphere instead.[53] Because methane's warming potential is higher than CO_2, flaring lowers total reported CO_2e emissions. However, it still generates GHG emissions while the methane gas is essentially wasted because it is not captured and sold or utilised for other purposes. Multiple technologies and abatement programmes are available to underground coal mines that BHP is not utilising. Regarding its open-cut mines, BHP has stated that methane abatement faces too many challenges, meaning it would rely on purchasing carbon offsets or reducing production to decrease methane emissions.

Whitehaven has not implemented methane abatement practices at any of its operating coal mines. This means the only methane emissions reductions made for its open-cut operations to meet its methane and GHG emission reduction targets would come from changes in reporting methods, changes in emission baselines, purchasing carbon offsets or decreasing production.

Questions investors could ask companies

- What specific actions are you taking to reduce methane emissions at each of your facilities (such as open-cut coal mines or LNG liquefaction plants)?
- Do you provide detailed information on specific actions you have taken and will take to reduce methane emissions by facility? If not, why not?
- **Open-cut coal mines:** Why have you not engaged in methane abatement at your open-cut operations? Please provide details of any steps you have taken, what barriers are you facng, and what are you doing to overcome them?
- **Underground coal mines:** Why have you not rolled out abatement technology at your underground operations, such as enhancing pre-drainage before mining, improved housekeeping or implementing VAM abatement? What barriers are you facing, and what are you doing to overcome them?
- **Oil & Gas:** What specific abatement action, such as equipment upgrades, have you implemented to reduce methane emissions, at which facilities, and what is the likely volume of abatement?
- **Oil & Gas:** Will you implement best-practice equipment and processes for all new growth projects, or if not why not? Please provide details of any planned actions, including likely volumes of abatement.

Oil & gas methane abatement options

A range of commercially available technologies can help Australian oil & gas producers materially reduce their methane emissions

The oil & gas industry body Australian Energy Producers (AEP) has noted the availability of suitable technologies to abate methane emissions, highlighting a number of case studies that clearly demonstrate the potential for Australia's oil & gas sectors to reduce methane emissions.[54] Rystad and the IEA similarly noted this potential, suggesting that Australia's oil & gas sectors could abate up to 90% of methane emissions through the use of available technologies, including:

- Implementing robust regimes to identify and repair unanticipated leaks.
- Replacing so-called "high-loss" equipment, which emits methane by design, with new low loss alternatives (which includes replacing wet seals with dry seals).
- Ending the use of venting and flaring, and ensuring flaring is efficient where used (i.e. flaring achieves maximum combustion to avoid methane being released in flaring exhaust).
- Recycling waste gas (which avoids the need for venting or flaring).
- Replace gas-driven devices (such as generators) with electric alternatives.[55]

Replacement of leaking pipelines and the conversion of wet compressor seals to dry seals are among the lowest cost, equating to between AU$10 and AU$60 per tonne of methane. More expensive options are the conversion from pneumatic to electric pumps, and the use of leak detection and repair (LDAR) technology, also known as measurement, reporting and verification (MRV). These costs range from AU$50 to AU$245 per tonne of methane for LDAR, and AU$740 for electric pumps.[56] Replacement of the compressor seals would make the largest single reduction among the technologies, and should be a high priority for companies given the low cost and potential to recover large volumes of methane for sale.

The majority (51%) of methane emissions reductions can potentially be abated at no cost to the operator. The financial benefits derived from those opportunities would more than offset the net costs of the rest of the potential. It is also worth noting that the suspected underreporting of methane emissions leads to cost overestimates – given that the cost of implementing the technologies would stay the same, but the revenues from selling the recovered gas would increase.

Some of these technologies are already being trialled in Australia. For example, AEP published a short report that outlined several methane monitoring and abatement case studies.[57] As noted previously by IEEFA, these case studies "clearly demonstrate the potential for Australia's oil and gas sectors to reduce their methane emissions".[58]

Notwithstanding the availability of methane abatement technologies, the most effective way to reduce Australia's oil & gas methane emissions is to reduce the production and use of gas in Australia. The looming supply glut in global LNG markets, in which the majority of Australia's gas is sold, may affect the financial case for new gas developments. It would therefore provide opportunities for Australia's gas producers to reduce production – and in turn decrease methane emissions. Further, the IEA found that aligning with the Paris Agreement would require a significant decrease in oil & gas production.[59]

Woodside and Santos have undertaken a range of initiatives to measure and reduce their fugitive methane emissions

The companies' methane abatement actions have not materially driven down their portfolio methane emissions.

Both Woodside and Santos have taken steps to better understand and abate their methane emissions.

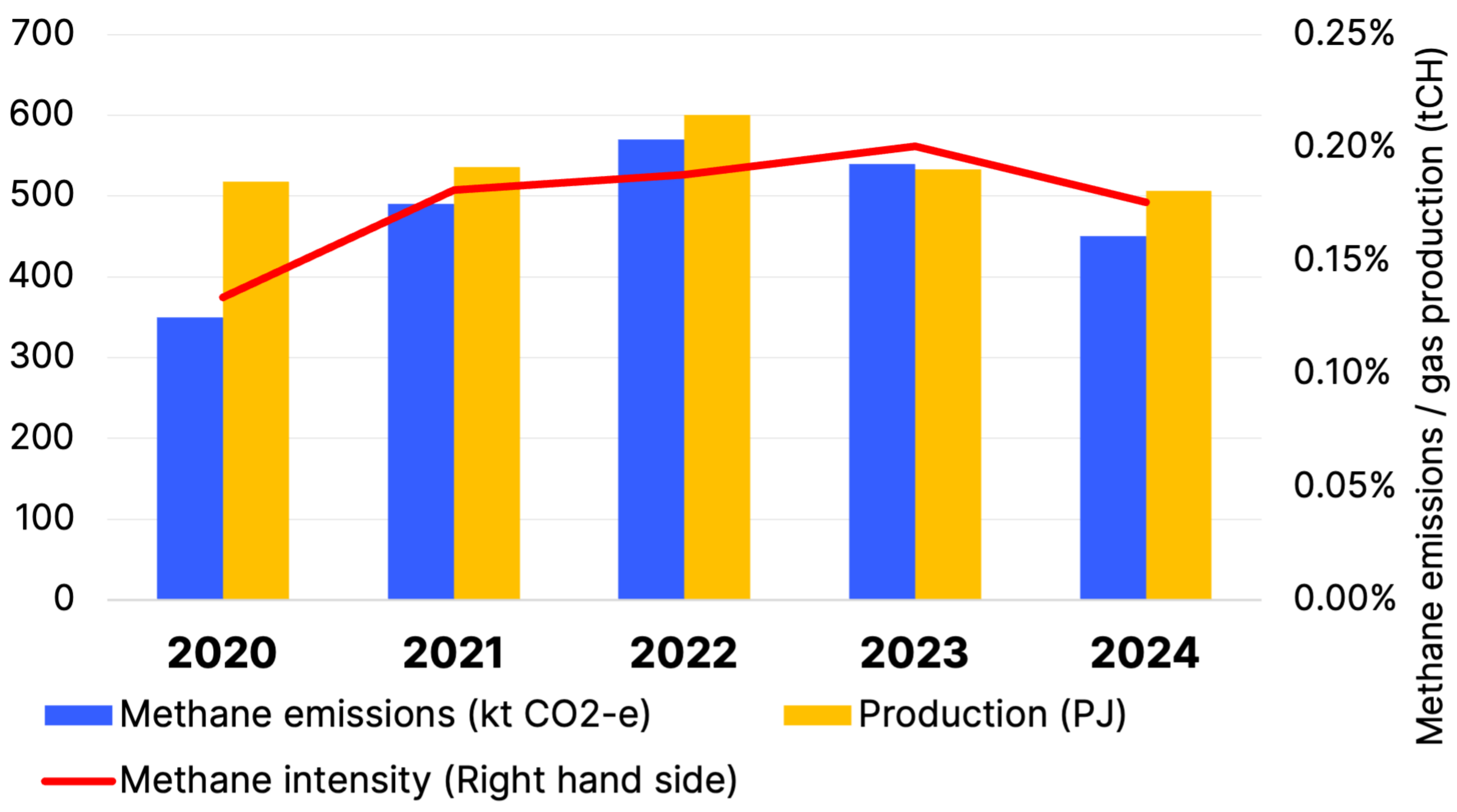
Santos has undertaken several projects to reduce gas flaring and venting across its portfolio, and has changed how it manages gas pipeline compressors at Moomba Gas Plant to eliminate the need for flaring.[60] This may have contributed to Santos's declining methane emissions since 2022. However, this fall in emissions is likely to also reflect the company's declining gas production given the correlation between its production and methane emissions since 2020 (Figure 13). IEEFA estimates Santos's methane emissions intensity increased from 2020 to 2023.

In 2023, Woodside implemented projects estimated to reduce methane emissions by 2ktpa (a 12% reduction to 16.75kt of reported methane emissions in 2024), including:

- Repair of a leak at the Karratha Gas Plant terminal.
- Changes to venting procedures.
- Optimisation of compressor seals.
- Redirection of gas venting to a flaring system.
- Installation of thermal oxidisers to reduce methane venting.[61]

While these initial abatement steps are positive, investors still do not have sufficient information to understand the scope and impact of abatement actions. Company disclosures should include detailed guidance on specific abatement actions by facility, and how these compare with best practice benchmarks. For example, the IEA and Rystad Energy suggest that globally, fugitive methane emissions from the oil & gas industry can be reduced by 90%.

Figure 13. Santos's methane emissions vs production levels



Source: Santos.[62]

APA has made limited progress reducing methane to date despite a number of abatement actions

APA's methane emissions were higher in FY2024 than in FY2020 due to growth projects and despite signalling a focus on abatement.

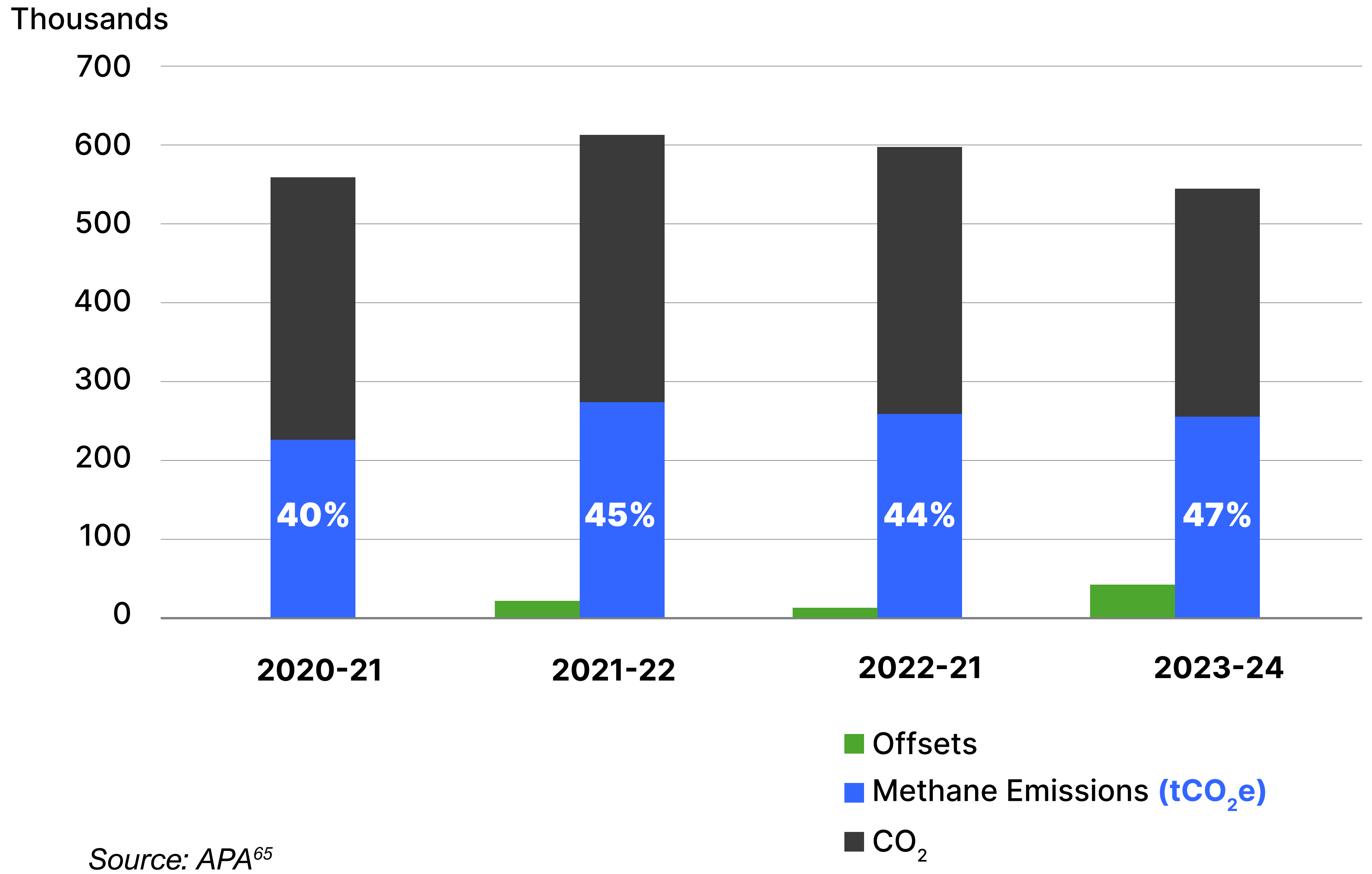
- APA has undertaken a number of steps as part of its methane emissions reduction strategy, including:
- Joining the Methane Guiding Principles.
- Trialling new measurement approaches to better understand its actual methane emissions; this has identified the SWQP as possibly having higher emissions than inventory estimates.
- Deploying portable flares to reduce methane venting.
- Trialling gas capture technology to avoid venting.
- Implementing seal upgrades at two facilities to reduce leaks.
- Undertaking several studies related to abatement opportunities, and developing a new leak management protocol to support LDAR. [63]

These steps appear to have driven slight reductions in APA's official (i.e. inventory) gas infrastructure methane emissions from FY2022 to FY2024. However, APA's methane emissions have actually increased since FY2021, both in absolute terms and as a share of APA's total gas infrastructure emissions (Figure 14).

APA's emissions increase reflects growth in its gas transmission volumes due to the east coast grid expansion and the GGP project in WA. APA reporting suggests that without these growth projects, the company's gross emissions (from gas infrastructure) in FY2024 would have fallen by 8% relative to FY2021. Therefore these projects directly increased APA's methane emissions (by about 22% from FY2021 to FY2024).[64] This increase in methane emissions may also have contributed to APA's increasing use of carbon offsets.

As noted earlier, APA is pursuing further growth projects that could affect its ability to meet its emissions reduction targets.

Figure 14: APA's gas infrastructure methane emissions FY2021-24



Source: APA[65]

Coal mine methane abatement options

Reducing coal production is the only method that allows for a 100% reduction in methane emissions in coal mining

As BHP and Whitehaven produce about 90% of their coal from open-cut mines, the simplest option to reduce methane emissions is to decrease production. The next biggest opportunities for methane abatement include implementing enhanced pre-drainage at open-cut operations, and VAM abatement and pre-drainage at underground operations.

However, regulatory incentives to pursue these initiatives remain limited under the current design of the SGM framework and the federal government's Australian Carbon Credit Unit (ACCU) scheme. Consequently, many miners are choosing to rely on purchasing carbon offsets instead of seeking to structurally abate fugitive methane.

IEEFA's previous report on methane featured analysis on abatement solutions available to both underground and open cut mines.[66]

Methane abatement at open cut mines is possible via pre-drainage.

Recent examples from QLD suggest that methane abatement at open-cut coal mines is feasible, and under certain conditions can be financially viable. For instance, Coronado Resources a methane pre-drainage trial system at its Curragh mine, using the methane to displace some diesel used in its truck fleet.[67]

Additionally, Stanmore Resources received government funding to capture methane for at least 15 years to power a new 20-megawatt gas-fired power station to be completed by 2027. The power station is expected to entirely offset Stanmore's South Walker Creek mine's electricity requirements. [68]

However, even if more open-cut coal mines conduct enhanced pre-drainage, studies show that only 60%-80% of methane can be captured and abated via this method. This means the only options that would allow open-cut miners to achieve net zero CO_2e emissions by 2050 are relying on purchasing carbon credits or reducing coal production. Due to limited numbers of methane-specific abatement projects generating carbon credits in Australia, reduced production remains the only method for companies to achieve net zero methane emissions by 2050 at this stage.

Several abatement technologies exist for underground mines.

Mature technologies exist to capture ventilation air methane (VAM), responsible for approximately 70%-80% of methane emissions from underground coal production.[69] Australian governments are funding the country's first full-scale regenerative thermal oxidation (RTO) project at the Kestrel underground metallurgical coal mine in the Bowen Basin in QLD. Continuing improvements in this space mean new technologies could extend the use of VAM abatement with even lower concentrations of methane.

Additional technology advancements are also enabling the captured methane to be used instead of combusted, as combustion generates CO_2 emissions.[60, 71] China leads the way in VAM abatement uptake, with 13 operational projects.[72] It has proposed making it mandatory for underground mines to "process coal mine gas with a concentration of 8% or less and ventilation air methane using flameless oxidation technology to produce heat for power generation".[73]

BHP claims abatement technology is not ready for open cuts

No methane abatement has been reported or is in prospect at BHP's open-cut coal mines, and only the minimum abatement actions have been taken at its underground mine.

BHP has stated it plans to spend an estimated US$4 billion (nominal terms) on decarbonisation plans through to FY2030, but it is unclear how much, if any, of this is specifically budgeted for methane abatement initiatives. In its 2024 Climate Transition Action Plan, BHP states that, "The majority of our capital expenditure profile in this decade is weighted towards diesel displacement and weighted towards the late 2020s."[74]

BHP states its abatement options for open cuts will focus on offsetting until technologies are 'ready to deploy'.

Approximately 93% of BHP's Australian coal production comes from open-cut mines. BHP asserts that a feasible pathway to net zero operational GHG emissions by 2050 will require the use of some offsetting, and that sourcing carbon credits will be needed to comply with the SGM.[75]

The company will prioritise structural abatement options over offsetting where applicable. However, so far, it has not taken any action on structural abatement at its open-cut operations. BHP says the reason for this is that many of the technologies and solutions needed to abate Scope 1 methane emissions are not "ready to be deployed", and accordingly that its "need for eligible carbon credits may grow over time to support compliance".[76] This contrasts with other open-cut miners that are taking action on methane emissions detailed on Page 24.

BHP performs the minimum required methane abatement at Broadmeadow, its only operating underground mine.

At Broadmeadow, BHP performs limited gas drainage and flaring. The company stated it abated approximately 85,000tCO_2e using this method in FY2024, or about 10% of the mine's reported emissions of 845,000tCO_2e.[77]

In addition to Broadmeadow, BHP has proposed a new underground mine complex to be developed at the existing open-cut Saraji mine site. It has also been granted approval for a new underground mine, the Red Hill project, to be developed near its existing open-cut Goonyella Riverside mine. For Saraji East, gas drainage (both pre-mine drainage and post-mining void or "goaf" drainage) and flaring are the only methane abatement measures proposed in its Environmental Impact Statement.[78] For Red Hill, the project was approved on the basis that BMA would "either use captured IMG [incidental mine gas] for the production of electricity or sell captured IMG to a third party".[79]

In QLD, the Mineral Resources Act (MRA) (2007)[80] outlines minimum requirements for underground coal mines. Underground mines must prepare the mine for operation by pre-draining excess gas. It is a requirement to flare captured methane if it is not technically or commercially feasible to utilise the gas and if it is safe to do so. Hence, the methane abatement actions undertaken at Broadmeadow and proposed for Saraji East are considered the minimum requirement to comply with the MRA.

Whitehaven has taken no action on methane, claiming costs are prohibitive

Whitehaven has not implemented methane abatement practices at any of its operating coal mines, including its highest-emitting mine, Narrabri Underground.

Narrabri is Whitehaven's only underground mine, and presents its greatest methane emissions reduction opportunity. Narrabri Underground is the largest source of Whitehaven's reported Scope 1 emissions, at 555ktCO_2e in FY2024. However, no methane abatement activities have been undertaken at Narrabri to date.

This includes not conducting pre-drainage, which is mandatory for underground mines in QLD, but not NSW. Pre-drainage reportedly does not occur at Narrabri because the mine contains low concentrations of methane, making pre-drainage and flaring difficult. As mining progresses into more methane-rich zones, a number of strategies have been proposed in the Narrabri Greenhouse Gas Minimisation Plan 2023.[81] These include:

- Conducting pre-drainage and flaring methane in concentrations greater than 30%, combined with low oxygen content to minimise risk.
- Improving seals in mined-out areas.
- Investigating methane enrichment plants to separate CO_2 from the methane.
- Considering ventilation air methane (VAM) abatement (Whitehaven asserted this would be cost and technologically prohibitive).

In 2024, the Narrabri South Stage 3 extension received federal approval under the EPBC Act. It was noted that, "beyond 2032 the proposed mine extension will see a significant increase in GHG emissions from current operations as a result of the longwalls being cut into an area where the coal seam has a higher CH4 content". [82]

The approval of the Narrabri South extension means unabated operations at the mine are effectively approved through to 2044.

Whitehaven's Narrabri application considered using methane for power generation but concluded that it was cost-prohibitive. Instead, Whitehaven states it will achieve emissions reduction targets through a combination of site-specific abatement initiatives and the use of carbon credits.[83] It has also pledged to implement enhanced longwall sealing of goafs and flaring of pre-mining drainage methane, and is also exploring methane capture.[84] However, to date no structural abatement action has been taken.

For Whitehaven's proposed Winchester South Project, it has proposed to implement traditional housekeeping methods, which can include regular maintenance of plant and equipment as well as regular monitoring and review and evaluation of GHG reduction opportunities.[85] However, there are no plans to implement structural methane abatement to mitigate fugitive gas emissions from this project.

Methane Costs

Fossil fuel companies face a range of costs arising from methane emissions including:

- **Forgone value arising from the loss of methane into the atmosphere.**
- **Rising costs of carbon offsets required to be surrendered to meet emissions baselines under the SGM.**
- **Production interruptions or prolonged shutdowns due to methane-related fires.**

APA	woodside	Santos	BHP	Whitehaven
Low	Low	Moderate	Moderate	Moderate

IEEFA estimates the forgone value for APA over the past four years ranges from A$1.6 million to A$18 million (depending on whether domestic or LNG prices are used as a reference). This is based on APA's reported methane emissions, although IEA data suggest actual emissions could be double that. APA has noted that a recent survey of one of its largest pipelines suggests its methane emissions may be underreported.

For Santos, the forgone value is significantly higher at almost AU$47 million in FY2022 (based on LNG netback prices). This could be as high as AU$94 million if Santos's actual methane emissions are double their reported levels.

Similarly, Woodside's methane emissions have eroded value, with IEEFA estimating a forgone value of almost AU$16 million in 2022, which again could be significantly higher if their methane emissions are underreported.

For coal mining companies, IEEFA's previous research indicated that 48.8 petajoules (PJ) of fugitive methane emissions could be captured and utilised or sold across the industry at an estimated value of AU$726 million.[86]

As noted earlier, there is growing evidence that Australia's coal mining and oil & gas methane emissions could be two or three times higher than reported.

Continued methane emissions may also lead to companies increasing their use of carbon offsets, which will have financial implications. IEEFA estimates the costs of fully offsetting methane emissions at more than AU$11 million for APA in 2022, more than AU$37 million for Woodside in 2024, and almost AU$23m for Santos in 2022 (at an assumed carbon credit price of $40/t$CO_2$-e).

However, these costs are relatively low when compared with each company's revenue and EBITDA, which for each company are as follows:

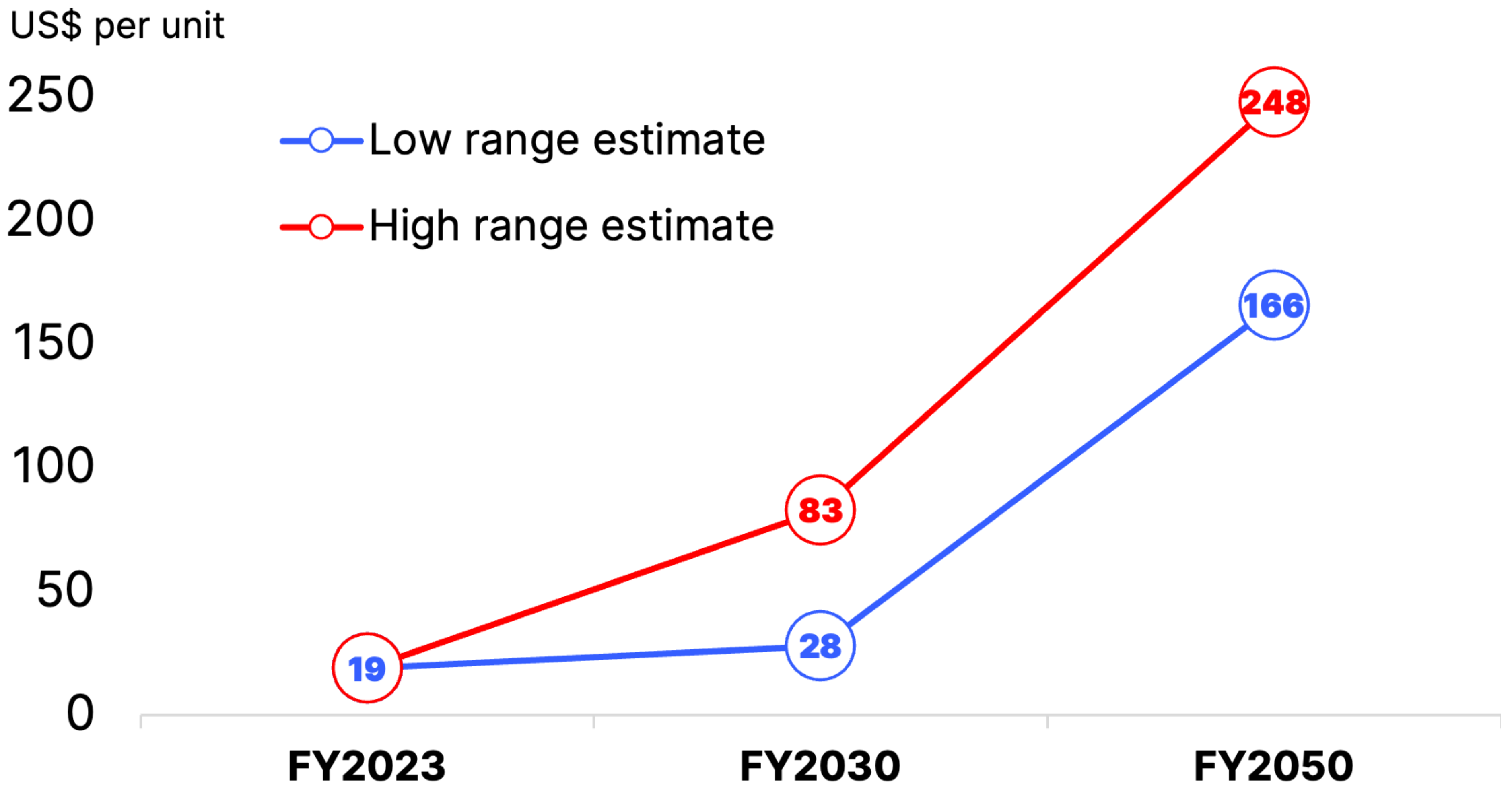
- APA reported AU$2.58 billion revenue and AU$1.89 billion EBITDA in FY2024.[87]
- Woodside reported US$13.18 billion revenue and US$9.28 billion EBITDA (excluding impairment) in 2024.[88]
- Santos reported US$5.38 billion revenue and US$3.7 billion EBITDA in 2024.

In practice, this may mean these companies have limited financial incentives to prioritise methane abatement over other investment opportunities.[89]

Companies not taking sufficient methane abatement action will be reliant on purchasing carbon offsets to meet their own company targets as well as to meet emissions baselines reduction requirements under the SGM.

The lack of material action on methane abatement at open-cut coal mines means the expected rising cost of carbon credits in Australia could increase operating costs. BHP expects average Australian carbon prices to range from US$28-$83 in FY2030 and US$166-$248 in 2050,[90] compared with an average of about US$19 in 2023.[91]

Figure 15: BHP's forecast Australian Carbon Credit Unit price, US$



Source: IEEFA; BHP[92]

Without undertaking structural methane abatement or decreasing coal production, BHP's methane and carbon offset costs could significantly increase between 2025 and 2030 and 2050. Based on the value of offsets purchased by BHP in FY2024, US$1 million (~47,000t$CO_2$e),[93] this would mean its total annual offset costs could rise 75%-420% to US$1.8-$5.2 million in 2030, and could be 27-40 times higher in 2050 at US$27-$40 million. Whitehaven has not publicly disclosed the number and value of offsets purchased in FY2024, so a comparison is not possible.

The calculations for BHP factor in an assumed 4.9% reduction in companies' emission baselines under the SGM each year, but do not factor in the expansion and potential increase in production capacity or the risk that methane emissions are significantly underreported. The risks of methane underreporting and the expansion plans of both miners could mean the carbon offset requirements are significantly higher than the above estimates.

High concentrations of methane in the general body of air can create an explosive atmosphere, leading to mine fires or explosions.[94] Methane-related fires can impose costs on companies. While methane fires can occur at open-cut operations, underground mines face significantly higher risks because the confined mining space can accumulate high concentrations of methane. Multiple methane-related fires or explosions have occurred in Australia, leading to the deaths and serious injuries of workers (Figure 16). The impacts of methane-related fires on companies include prolonged shutdowns and reduced production, damage to equipment, and costs associated with enforceable undertakings or fines if the incident is found to be caused by a violation of workplace health and safety standards.

Figure 16: Mine disasters and closures following methane-related fires or explosions

	Year	Deaths	Injuries
Box Flat Colliery Disaster	1972	17	9
Appin Mine Disaster	1979	14	27
Moura No. 2 Mine explosion	1994	11	0
Grosvenor Mine methane explosion	2020	0	5
Grosvenor Mine fire	2024	0	0

Source: IEEFA.[95]

Questions investors could ask companies

- Have you conducted a comprehensive cost-benefit analysis (CBA) on methane abatement for each of your projects or facilities? If not, why not? If yes, what were the results?
- Are there barriers impeding your ability to capture and sell methane for additional revenue? What are you doing to overcome these barriers?

APA could be wasting AU$10-20 million each year by not prioritising methane abatement

APA's methane emissions are eroding value to its shippers, and may contribute to its carbon offset costs.

IEEFA estimates the forgone value of methane emitted by APA operations ranges from slightly less than AU$2 million in FY2021 (when domestic gas prices were low) to AU$4.5 million in FY2024. However, if we assume lost methane would have been sold into LNG spot markets, the forgone value rises to as high as AU$18million in FY2023. Accounting for underreporting, and noting the IEA's finding that the Australian oil & gas sector's methane emissions could be double company reported emissions, this forgone value could have been as high as AU$36 million in FY2023.

While methane emission abatement clearly makes financial sense, the relative costs associated with not taking action may not be material to APA, which had revenue of just over AU$2.9 billion in FY2023.[96]

APA faces limited financial incentives to prioritise methane abatement.

APA's continued focus on growth, rather than prioritising methane abatement, likely reflects its relatively limited financial incentives to abate methane.

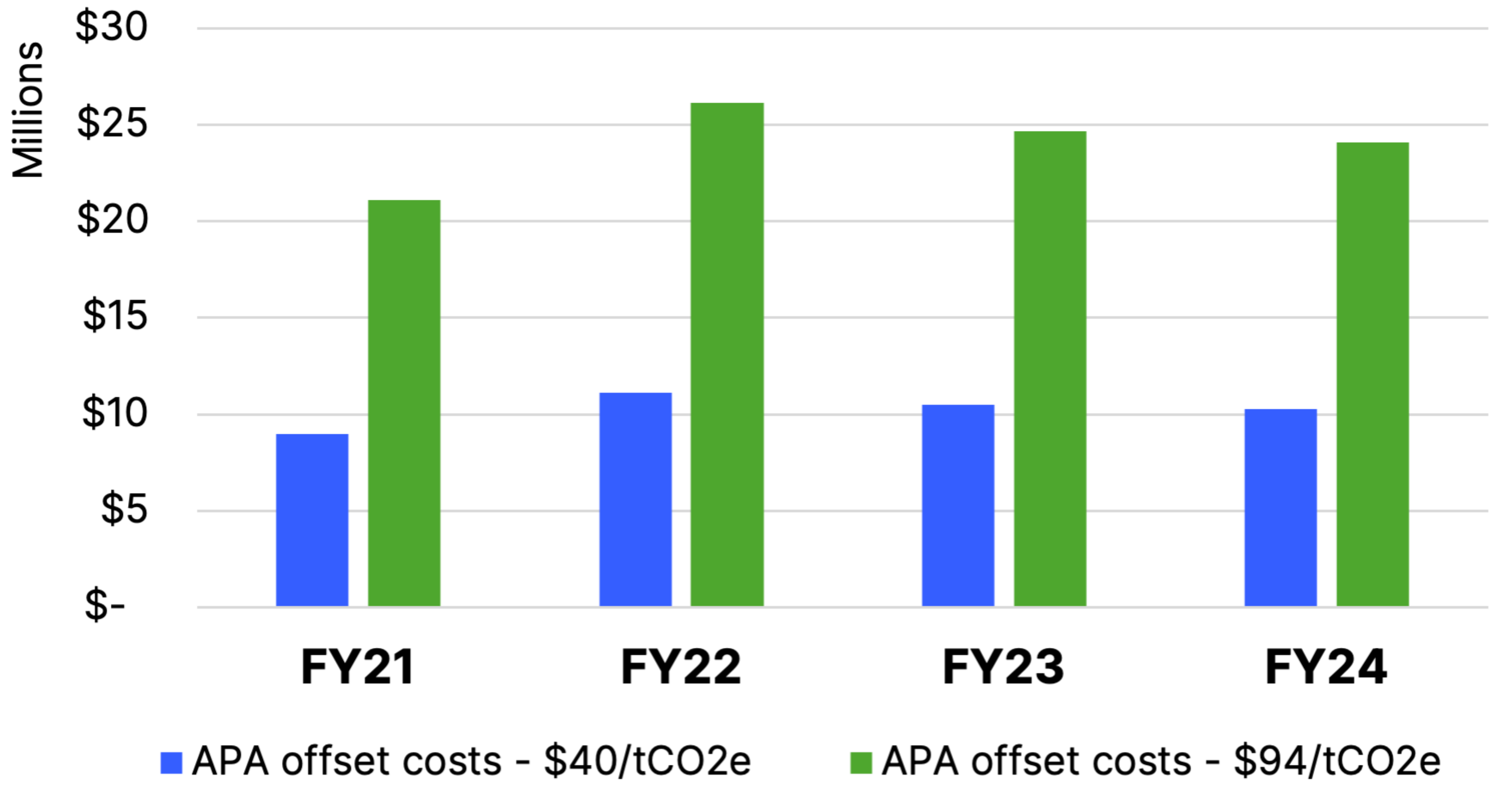
Moreover, under APA's contracting arrangements, it is not contractually required to "pay" for any methane emitted from its gas infrastructure. Instead, gas shippers are required to provide System Use Gas, which includes any gas that is lost within the system.[97]

The SGM also does not incentivise APA to reduce methane emissions. This reflects two factors: only two APA facilities (SWQP and GGP) are subject to the Mechanism; and total emissions from these facilities were below their respective baselines in the most recently available data (FY2023).

The costs of offsetting APA's methane emissions are likely to be relatively low even if APA were required to fully offset all methane emissions (Figure 17). Based on APA's emissions reporting, fully offsetting all methane emissions would cost about AU$10 million at a carbon price of AU$40/t$CO_2$e, rising to more than AU$25 million in FY2024 using APA's internal carbon price of AU$94/t$CO_2$e.

In practice, the availability of offsets, and their relatively low cost, may also create disincentives to genuine methane abatement despite the strong financial case for methane abatement.

Figure 17: Estimated costs to fully offset APA's methane emissions, AU$



Source: IEEFA estimates. Note: APA's internal carbon price is set at AU$94/t$CO_2$e.

Conclusion

Overall, the simplest strategy for these companies to decrease methane emissions is to decrease coal and gas production in line with their climate-and sustainability-related targets. This would have the additional benefits of minimising their exposure to long-term declining global market demand for Australian coal and LNG.

For Australian coal mining companies BHP and Whitehaven, a proactive and rapid move to higher-order estimation methods combined with independent review and verification methods should be an urgent priority. For both companies, this would reduce the risk that they may be significantly underreporting their methane emissions.

Both companies have reported lower emissions after switching from Method 1 to Method 2 estimates. Given that the IEA and data from independent organisations ClimateTRACE and OpenMethane suggest coal mine methane could be more than three times higher than reported, the recent reductions in reported emissions by changing estimation methods means underreporting risks could be increasing for these companies.

Additionally, neither company has conducted methane abatement action at their open-cut mines, in contrast to some other miners. As two of Australia's largest coal producers, Whitehaven and BHP should be leading the way in coal mine methane abatement practices. The examples set by other coal mining companies in Australia, and the technological advances they have made, demonstrate that action can be taken to target methane emissions, both from open-cut and underground coal mines.

Australian oil & gas companies face several key risks arising from their methane emissions and their current approaches to estimation. These include financial risks such as lost revenue and potentially higher carbon offset costs. The possibility of underreporting due to continued use of emission factor estimation methodologies magnifies these financial risks.

More broadly, the industry faces the risk of declining social licence due to continued methane emissions and the prioritisation of growth over abatement, which could have a material impact on future operations. Specifically, methane emissions and the increasing awareness of potential underreporting undercut the industry's narrative that gas is cleaner than coal, and is therefore a crucial transition fuel.

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About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy.
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